ATTACHMENT B

Revised Assumptions and Calculations for Northwest Default Emission Factor for Unspecified Sources

This attachment documents how the Northwest emission factors for unspecified purchases were changed due to parties' comments on the staff reporting proposal, issued by Administrative Law Judge ruling on June 12, 2007. The modifications result in a change in the proposed emission factor from 419 lbs/MWh to 714 lbs/MWh.

The basic methodology remains the same, but some of the Northwest resource mix assumptions changed to alter the default emission factor results. The basic methodology first establishes an import and export limit furnished by the balancing authority. All specified purchases from the Northwest are subtracted from the Northwest electricity imports total and the remaining purchases are classified as unspecified imports. The unspecified imports are typically spot market and portfolio based transactions. The default emission factor is then calculated and would be applied by the Air Resources Board to the Retail Providers' unspecified purchases.

To derive the resource mix assumptions, the Northwest electricity imports were divided into three principal seller groups: British Columbia (BC) Hydro, utilities and power marketers/merchant generators. An analysis of Bonneville Power Administration (BPA) electricity transactions was also conducted since the federal hydro system is a primary source for electricity sales to regional utilities and to power marketers. BPA also provides direct spot market sales to California. Assumptions are made about the resource portfolio that each seller has available for transactions with California load serving entities.

The June 12 staff proposed reporting protocol contained a Resource Mix and Default Emission Factor estimate for the unspecified 2005 Northwest imports that is shown in Table B-1. These resource mix estimates are what parties commented on and is the starting point for the final revisions.

Table B-1

Staff Reporting Protocol Assumptions for 2005 Northwest Specified and Unspecified Electricity Imports Resource Mix (Imports = Thousand MWh and Emission Factor = lbs/MWh)

Imports	Hydro	Coal	Gas	Nuclear	Renewables	Other	Total
Specified Mix	1,432	565	0	161	251	0	2,409
Unspecified Mix							
BC Hydro	4,135	0	0	0	0	0	4,135
Marketers	3,523	282	3,241	0	0	0	7,046
Utilities	4,153	1,318	677	305	249	9	6,711
Subtotal	11,811	1,600	3,918	305	249	9	17,892
Total Imports	13,243	2,165	3,918	466	500	9	20,301
Unspecified Share							
BC Hydro	100%	0%	0%	0%	0%	0%	100%
Marketers/Merchant Generators	50%	4%	46%	0%	0%	0%	100%
Utilities	62%	20%	10%	5%	4%	0%	100%
Total	66%	9%	22%	2%	1%	0%	100%
Unspecified Emission Factor (lbs/MWh)	0	2,307	982	0	0	0	419

Source: Attachment A to the June 12, 2007 ALJ Ruling, " Joint California Public Utilities Commission and California Energy Commission Staff Proposal for an Electricity Retail Provider GHG Reporting Protocol", page 24 and derived in a March 2007 staff paper that was also subject to public comment.

The following sections provide a description of the reasons for changes to the unspecified resource mix assumptions and calculated default emission factor.

1.1 Step 1: Correcting Data Input Error

Although no party provided comments on this issue, staff found a small input error in the calculated electricity imports split among the three types of Northwest sellers. The data for this estimate comes from three years of Federal Energy Regulatory Commission (FERC) and Energy Information Agency (EIA) data, including those years when complete reports from Investor-Owned Utilities and Publicly-Owned Utilities were available. These transaction estimates did not include direct non-firm energy sales from the BPA since their sales are not reported to either FERC or EIA. Staff did investigate the amounts of electricity that BPA sold to California, but this information was inadvertently omitted from the March 2007 resource mix estimates.

While preparing the March 2007 Staff Resource Mix paper, staff evaluated the operations and role that the federal hydro system has on the Northwest regional market to determine how much electricity is sold to California beyond the amounts reported under specified contracts. The March 2007 paper does describe the role of the federal hydro system that is operated by BPA and includes a study that shows that the amount of Northwest electricity imports is strongly correlated with hydro-generation.

BPA does sell surplus electricity to Northwest utilities and marketers, and some then resell this electricity to other western markets. This fact is included in the marketer and utility sales assumptions in the March 2007 report. However, BPA also sells about 10,000,000 MWh of surplus electricity that is delivered beyond the Northwest region each year. BPA does sell some of this surplus electricity to directly to California parties (load selling entities, marketers, merchant generators and the California Independent System Operator). BPA staff indicated that they delivered about 2,400,000 MWh of electricity over the Pacific Intertie in 2005, which is in addition to the specified contracts (1,600,000 MWh) that is reported in their power source disclosure filings to the Energy Commission. Some of this electricity could have been wheeled through California and sold to the Southwest market. Staff originally intended to add a conservative amount of the BPA deliveries to the Northwest utility sales to California.

The corrected split now includes the assumed electricity sales from BPA, added as utility sales to California. The result increases the total sales from Northwest utilities from 38 percent to 45 percent, decreasing the amounts from marketers from 39 percent to 32 percent. Details are provided in Table B-2.

Table B-2

Comparison of the Original and Alternative Split Among Northwest Unspecified Sellers in 2005 (Thousand MWh)

Sellers	Original		Alternative	
BC Hydro	23%	4,135	23%	4,135
Marketers	39%	7,044	32%	5,703
Utilities	38%	6,710	45%	8,050
Total	100%	17,888	100%	17,888

The corrected split among Northwest sellers is then applied to the assumed resource mix for each provider type to calculate the default emission factor.

1.2 Adjustments Based on Filed Comments

Two major changes were made in response to the comments from parties. The Washington Department of Community, Trade and Economic Development (CTED) determined that the emission factor for Northwest Power Pool residual electricity that is available for sales to California is 1,062 lbs/MWh (July 10, 2007, page 1). The Northwest unspecified resource mix emission factor for utilities selling to California was thereby changed to the value provided by the Washing CTED. The calculation for this change is explained in Steps 1 and 2 below. The second change pertains to the recommendation from parties that marketers were buying a greater percentage of coal and that the Southwest resource mix analysis should be similarly applied to the Northwest assumptions. This recommendation was considered and partially applied to estimate the default emission factor, addressed in Step 3. The combination of the changes described in Steps 1, 2, and 3 results in a revised emission factor of 714 lbs/MWh. The party recommendations that were not adopted are discussed in the section after Step 3.

STEP 1: Assume that the Utilities purchase the Washington and Oregon residual generation mix; Marketers mix remains the same as the June 7 proposal (hydro 50%, Coal 4%, Gas 46%)

Issue: Oregon and Washington recommend that Northwest utility emissions be based on the residual resource mix rather than the system average mix as proposed in the draft protocol. The Oregon and Washington recommendation is a reasonable alternative, applied only to electricity sales from Northwest utilities. The decision concurs with the recommendation that the unspecified sales from Northwest utilities should be calculated at the default residual mix. Table B-3 provides the resource mix and default emission factor results from applying the residual generation mix to utilities selling electricity to California.

Table B-3

NWPP Residual Mix Applied to Utilities
(Imports = Thousand MWh and Emission Factor = lbs/MWh)

Unspecified Mix	Hydro	Coal	Gas	Nuclear	Renewables	Other	Total
BC Hydro	4,135	0	0	0	0	0	4,135
Marketers	2,852	228	2,624	0	0	0	5,703
Utilities	3,293	3,395	1,028	208	118	7	8,050
Total	10,280	3,623	3,652	208	118	7	17,888
Percent Share							
BC Hydro	100%	0%	0%	0%	0%	0%	100%
Marketers	50%	4%	46%	0%	0%	0%	100%
Utilities	41%	42%	13%	3%	1%	0%	100%
Total	57%	20%	20%	1%	1%	0%	100%
Emission Factors	0	467	200	0	0	0	668

STEP 2: Assume that Utilities do not sell nuclear or renewables, which amounts are shifted to hydro and adjustments to coal & gas so that the Utility emission factor equal close to the Washington and Oregon calculation of 1062 lbs/MWh (calculated at 1063 lbs/MWh)

Issue: Should we assume that all renewables and nuclear not claimed in known contracts be retained in the Northwest to meet their renewable portfolio standard and because nuclear is fully subscribed? This decision accepts this policy interpretation for the small amount of renewables and nuclear energy left in the residual mix.

Issue: There is currently a small discrepancy between the emission factor calculated by the Washington CTED and those used by California. If the default resource mix was applied to the Northwest utility assumption, the resulting default emission factor for utilities would be 1,098 lbs/MWh instead of the 1,062 lbs/Mwh value calculated by the Washington CTED. Since the default value was specified in Washington CTED letter, a small change to the utility resource mix was made in order to arrive at the recommended default rate. Table B-4 provides the resource mix and default emission results when applying the Washington and Oregon residual resource mix and the Washington CTED emission factor to utility sales.

Table B-4

NWPP Residual Generation, Shift Nuclear and Renewables, and Use Washington Emission Factor Applied to Utilities (Imports = Thousand MWh and Emission Factor = lbs/MWh)

Unspecified Mix	Hydro	Coal	Gas	Nuclear	Renewables	Other	Total
BC Hydro	4,135	0	0	0	0	0	4,135
Marketers	2,852	228	2,624	0	0	0	5,703
Utilities	3,622	3,180	1,248	0	0	0	8,050
Total	10,609	3,408	3,871	0	0	0	17,888
Percent Share							
BC Hydro	100%	0%	0%	0%	0%	0%	100%
Marketers	50%	4%	46%	0%	0%	0%	100%
Utilities	45%	40%	16%	0%	0%	0%	100%
Total	59%	19%	22%	0%	0%	0%	100%
Emission Factors	0	439	213	0	0	0	652

STEP 3: Utilities resource mix assumptions same as STEP 2; the Marketer split is based on the Southwest coal assumption. The Marketer hydro and gas split is adjusted to reflect ownership of merchant gas-fired power plants.

Issue: Parties recommend a marginal modeling method, but the result would show that all or most of the marginal resources are coal and natural gas, removing hydro from the mix. Hydro-generation is in fact sold to California, so the modeling results would not provide a realistic characterization of the system. The Centralia power plant is actually a merchant facility and the owners do sells electricity to the western market. The decision thereby applies the same coal generation mix assumption used in the Southwest resource mix calculation (10 percent) to Northwest Marketers selling to California. The balance of the Marketer sales is divided among the hydro and gas resources. The hydro sales assumption dropped, shifting mostly to the coal split and in part to the gas resources. Since BPA is now added to the Utility split, we are assuming that there is less non-firm hydro that marketers buy and resell to

California. The gas portion increases since some of the Northwest marketers also own the merchant gas generation in the region.

The resulting default emission factor, when applying the adjustments that are identified in Steps 1, 2 and 3 is now 714 lbs/MWh, as shown in Table B-4.

Table B-4

Step 2 Assumptions And Southwest Coal Assumption Applied to Marketer Sales (Imports = Thousand MWh and Emission Factor = lbs/MWh)

Unspecified Mix	Hydro	Coal	Gas	Nuclear	Renewables	Other	Total
BC Hydro	4,135	0	0	0	0	0	4,135
Marketers	2,253	598	2,880	0	0	0	5,703
Utilities	3,622	3,180	1,248	0	0	0	8,050
Total	10,010	3,778	4,127	0	0	0	17,888
Percent Share							
BC Hydro	100%	0%	0%	0%	0%	0%	100%
Marketers	40%	10%	50%	0%	0%	0%	100%
Utilities	45%	40%	16%	0%	0%	0%	100%
Total	56%	21%	23%	0%	0%	0%	100%
Emission Factors	0	487	227	0	0	0	714

1.3 Recommended Changes by Some Parties, But Not Accepted

Issue : Should the hybrid seller-based method for the Northwest be replaced with a production-cost model, marginal analysis? SCPPA and PG&E argued that a production cost modeling method should be used instead of the hybrid modeling and seller-based method that relies more on historic data.

The decision is to not accept this recommendation, based on the evidence presented in the comments in and following the April 12 workshop on the 2007 Resource Mix staff analysis.

- The "hybrid method" directly incorporates the complex way the Columbia River hydro is managed to serve multiple energy and non-energy objectives and to maximize sales from non-firm hydro.
- Electricity production cost models do not capture the market dynamics of how the BPA hydro may be sold in the market, especially since the Bonneville Power Administration actually sells surplus (after meeting firm load and public preference obligations) non-firm energy at market prices that hover around the marginal cost of natural gas-fired generation facilities.

- Earlier comments requested analysis to focus more on actual historic data and less on the results of production cost modeling.
- BPA's Annual Report documents that sales outside the Northwest amounted to $600,765,000 in 2005 and $691,508,000 in 2006, This translates to about 10,000,000 MWhs (assuming a market price of $60/MWh).

Issue: Should the Northwest get a priori claim to all Northwest hydro? SCPPA and PG&E argued that if coal were generated in the Northwest to serve the combined needs of the Northwest and California, that California should be charged the coal emissions even if they paid the higher price of hydro. The argument was made that if California had not been in the market, the Northwest would buy the surplus hydro at a market price that reflected fewer buyers.

This argument is not supported by the evidence in the record. California entities paid the higher price for non-firm hydro, which was priced closer to natural gas than to coal. No party disputes the fact that California paid for hydro. The Northwest does not have an exclusive claim on the Columbia River; BPA has an obligation to offer the surplus generation to Northwest utilities and have the flexibility to set market prices. The market prices are typically higher than Northwest utility generation costs, so there is no economic benefit to purchase non-firm energy above their own load needs. The argument could be extended to say that the whole West caused a cascade of everything else to generate, so everyone should be charged with the emission factor of the last unit dispatched, which would be a natural gas unit.

Issue: Should some or all of the specific proposals from Oregon or Washington be adopted?

As noted in Steps 1 and 2, recommendations of the two states to use the default emission factors for their Northwest utilities were adopted. Most parties recommended primarily that the states should work together on mutual future improvements as Oregon and Washington recommended. This decision concurs that the three states should commit to developing seamless tracking rules. That work should commence so that revised input assumptions can be available by the start of the 2009 reporting period.

The actual proposals of Oregon and Washington were not supported by the six commenting California parties, for a variety of reasons. The Community Environmental Council finds merits both in the analysis of the draft protocol and in the counter-claims of the two states, and recommends splitting the difference. PG&E, SCE and SCPPA propose using a marginal method for the Northwest, though each expects a different outcome.

Issue: Is there double-counting of hydro between what is claimed for Oregon and Washington and what is proposed for California? No, enough hydropower was generated in the Northwest to serve all the claims of Oregon, Washington and the California firm and non-firm sales. This has been confirmed by independent calculations by both Northwest and California staffs.

(END OF ATTACHMENT B)